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BEFORE THE ARIZONA CORPORATION COMMISSION

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IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	Docket No. E-04204A-09-0206

Arizona Corporation Commission
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NOTICE OF FILING DIRECT RATE DESIGN TESTIMONY

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Direct Rate Design Testimony of Ben Johnson, Ph.D., in the above- referenced matter.

RESPECTFULLY SUBMITTED this 13th day of November, 2009.

Daniel W. Pozefsky
Chief Counsel

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UNS ELECTRIC, INC.

DOCKET NO. E-04204A-09-0206

DIRECT RATE DESIGN TESTIMONY

OF

BEN JOHNSON, Ph.D.

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

NOVEMBER 13, 2009

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TESTIMONY

OF BEN JOHNSON, PH.D.

On Behalf of

The Residential Utility Consumer Office

Before the

Arizona Corporation Commission

Docket No. E-04204A-09-0206

Introduction

Q. Would you please state your name and address?

A. Ben Johnson, 3854-2 Killearn Court, Tallahassee, Florida.

Q. What is your present occupation?

A. I am a consulting economist and president of Ben Johnson Associates, Inc.®, an economic research firm specializing in public utility regulation.

Q. Have you prepared an appendix that describes your qualifications in regulatory and utility economics?

A. Yes. Appendix A, attached to my testimony, will serve this purpose.

Q. Are you the same Ben Johnson that filed revenue requirements testimony on November 6th, 2009?

A. Yes, I am.

Q. Have you prepared any schedules to be filed with your testimony?

A. Yes, Schedules BJ-11 through BJ-13, which are attached to my testimony, were prepared under my supervision.

Q. What is the nature of this testimony?

A. Our firm has been retained by the Residential Utility Consumer Office ("RUCO") to assist with RUCO's evaluation of UNS Electric, Inc.'s (UNSE's) Application for a rate increase. The purpose of this testimony is to present RUCO's rate design recommendations.

Following this introduction, my testimony has five sections. In the first section, I briefly discuss the background of the rate design phase of the proceeding. In the second section, I summarize UNSE's cost of service methodology and rate design proposals. In the third section, I discuss fully allocated cost of service studies, focusing on the Company's Average and Peaks methodology. In the fourth section, I discuss the Company's proposed revenue distribution and offer some suggestions for an alternative approach. In the fifth section, I critique the Company's current and proposed residential rates, and recommend some changes to the Company's proposed rate design.

I. Background

Q. Can you briefly discuss UNSE's most recent rate case?

A. Yes. On December 15, 2006, UNSE filed an application requesting a revenue increase of

$8,468,638. The Commission determined that the Company was entitled to a revenue increase of $4,018,678, or 2.5% over adjusted test year revenues. [Decision 70360, p. 80] The Commission rejected UNSE class allocation approach, and instead determined that the class responsibility for the revenue requirement should be allocated using the methodology of Staff's rate design expert witness. [Id.] Among other things, the Commission also: approved increases in customer charges, but not to the extent requested by the Company; approved an inverted block rate design for residential and small general service customers; approved an additional purchased power and fuel adjustment charge; rejected mandatory time of use rates; rejected a proposal to modify existing volumetric discounts for CAREs customers; and, approved certain low income customer commitments.

II. UNSE's Cost of Service and Rate Design Proposals

Q. Can you briefly summarize UNSE's proposals in this phase of the proceeding, beginning with its cost of service study?

A. Yes. UNSE's cost study methodology is a multi-step process. First, costs were "functionalized" by grouping costs with similar purposes or functions. [Erdwurm Direct, p. 11] The functionalized costs were then classified into demand-related, energy-related or customer-related costs. [Id.] Finally, the functionalized and classified costs were allocated to service classes using various allocation factors. [Id.]

Q. Can you expain the "functionalization", "classification" and "allocation" steps in a little more detail?

A. Yes. Examples of functions include transmission, distribution-primary lines, and metering. In total, UNSE identified over 20 different functions in its Class Cost of Service Study (CCOSS).

Certain of these costs were classified as demand, on the theory that these costs are most affected by the level of kW demand. [Id., p. 12] In general, these costs are viewed as being incurred on either a coincident basis (occurring at the same time) or non-coincident (varying as a function of peak demands within specific portions of the system, which could potentially vary with respect to the time when those individual peaks occur).

> Coincident demands tend to be more correlated with cost at the production level. In other words, *coincident demands* address whether there is purchased power and generation capacity for UNS Electric's entire system needs. Consequently, non-coincident demands become more correlated with cost as we move downstream though the distribution system to the end-users. [Id.]

Costs classified as energy are most affected by kWh by class. Some of these costs can vary by time-of-day. Costs that were viewed as being customer-related were assumed to vary based on class customer counts, weighted by relative levels of costs imposed by different types of customers, or in some cases on a uniform (non-weighted) basis. [Id.]

"Allocation" involves applying factors (e.g., peak demand contribution, energy or customers) to spread the costs to particular customer classes and rate schedules. Allocation factors can be external or internal. "External allocation factors are determined independent of the magnitude of specific costs in the CCOSS". [Id., p. 13] For example, "distribution stations-demand sub-transmission" costs are allocated based on non-coincident peak demands. [Id., pp. 13-14] Internal allocation factor are based upon cost components within the cost of service model. For example, Deferred Taxes and Tax Credits are allocated based on Total Plant in Service. [Id., p. 15]

Q. Can you provide a few examples of how UNSE applies allocation factors to costs?

A. UNSE used the Average and Peaks Method to allocate production costs. [Id., p. 14] This factor is made up of two components: an average demand component (with a percentage weight of the system load factor) and a peak demand component (with a percentage weight of one minus the system load factor). [Id., p. 15]

> The average demand component was calculated by dividing the number of hours in the test-year into the loss-adjusted energy. The peak demand component was calculated as a combination of coincident peak demands (time of system peak) from June, July, August, and September of the test-year. [Id.]

UNSE uses its "EFUEL" allocation factor to allocate purchased power costs. This factor is based on energy, and has no peak component. [Id., p. 14] The Company explains:

> In the last general rate case, the Commission's order indicated that all purchased power expenses should be based on energy. The Company's preferred method is to allocate a portion of purchased power costs using the Average and Peaks Method; however the Company is not proposing this method in this proceeding. In the last case, Staff argued that purchased power was billed to the Company entirely on an energy basis, and therefore energy should be used to allocate it. While the Company believes that the use of Average and Peaks is more appropriate for at least a portion of purchased power, the Company's rate design proposal would remain unchanged regardless of how purchased power is allocated. The allocation of the proposed rate increase is based more on customer impact than cost allocation, so the argument of whether to use Average and Peaks or energy becomes purely academic, and inconsequential from a practical standpoint. The customer impact issue is especially important in this case, given current economic conditions. The Company may again propose the Average and Peak method to allocate a portion of purchased power in the future, in a case where class cost causation is given more emphasis relative to customer impact. [Id.]

UNSE also uses the Average and Peaks method to allocate transmission and subtransmission costs. [Id., p. 15-16]

Q. Can you now summarize UNSE's rate design methodology?

A. In designing its proposed rates, UNSE considered the impact on customers and the "benefits of moving to cost-based rates". [Id., p. 18]

> The Company's approach promotes "gradualism." It avoids large percentage differences in class revenue increases. In other words, we balanced the future need to move each class towards rates that are more reflective of cost of service while recognizing that such a move must be tempered with other factors like gradualism, and the avoidance of "rate shock". [Id.]

UNSE's proposes to increase all classes by a uniform percentage amount of 9.21%, except Residential CARES, which is -9.41%, when compared to the adjusted test year revenues (taking into account weather normalization and the rate changes approved in the last rate case). When compared to unadjusted test-year revenue, there are minor differences in the percentage increases, as shown in the following chart. [Schedule H-1]

Class	Change in Unadjusted Revenues	Change in Adjusted Revenues
Residential:	7.98%	9.21%
Residential CARES:	-9.04%	-9.41%
Small General Service:	8.36%	9.21%
Large General Service:	8.03%	9.21%
Large Power Service:	7.95%	9.21%
Interruptible Power Service:	10.06%	9.21%
Lighting:	8.39%	9.21%

III. Fully Allocated Embedded Costs

Q. Let's turn to the next section of your testimony. Can you provide a brief description of fully allocated embedded cost studies, and explain what they measure?

A. Certainly. Fully allocated cost of service studies divide total test-year revenues, rate base, and operating expenses among the various customer classes to estimate the rate of return earned from each class. Many of these costs are either joint or common costs not directly attributable to any one customer class; therefore, they must be allocated by a formula. This opens the door to subjective judgments, and the results of the study tend to depend heavily on the particular allocation formulas chosen by the analyst.

Because they are based upon embedded costs, these studies do not report direct cause-and-effect relationships between the consumption decisions of the class members and the costs incurred by the utility. Thus a "cost" is not necessarily the actual expense that a particular group of customers imposes on the system. Nevertheless, cost of service studies have long been used by this Commission and other regulators as a tool that can assist with the process of developing electric and gas rates. As long as their limitations are recognized, and reasonable allocation formulas are employed, fully allocated cost studies can help the Commission in determining an appropriate revenue distribution.

Q. Can the judgment and arbitrariness be eliminated, if the analyst is completely unbiased and if sufficient effort is applied to the task?

A. No. The problem lies neither with the people performing the studies nor with the amount of effort and resources devoted to the analysis. Rather, it is inherent in the very concept of allocating embedded costs. To a large degree, these costs are the result of management and engineering decisions which reflect many different considerations, are completely outside the control of individual customers or customer classes, and thus cannot be unambiguously traced to customers. While the goal may be to insure that each customer class pays the costs that it causes, it simply isn't possible to achieve this result by allocating historical accounting costs.

Even when the actions of particular customer classes do influence such decisions, the linkage is largely indirect, and is obscured by the passage of time. For instance, customers influence the transmission costs incurred during the test year; but these influences are almost entirely traceable to customer actions (and subsequent management decisions) that occurred years ago, when the transmission lines serving today's customers were originally planned and constructed. Hence, the cause and effect links between today's customers (or customers present during the test year) and test year costs are inherently impossible to measure through the techniques used in developing an embedded cost of service study. All of the various alternative allocation formulas rely upon statistics relating to the test year, and none of them can possibly reflect with exactness the historic relationships of cause and effect that explain the embedded accounting costs reflected in the test year data.

This problem is particularly severe in this case, because UNSE obtains most of its energy through power purchase contracts, rather than generating the power itself. While these contractual arrangements are structured around per-KWH charges, it is reasonable to surmise that various other factors besides energy consumption (e.g. coincident peak demand or the UNSE average system load factor) have some influence on the price that is charged for these purchases, at least to some degree. For these and other reasons, there is no "perfect" formula for allocating most, if not all, of the costs incurred by UNSE, including the cost of transmission and distribution. Some cost allocation experts will sometimes imply their approach is the "true" answer, and that any significantly different approach is a heresy not to be condoned. I disagree with that viewpoint. There is no "correct" method for allocating joint and common costs, and any attempt to locate it will ultimately prove fruitless.

Embedded cost allocation studies are simply a technique for evaluating the relative fractions of the total revenue requirement that can reasonably be recovered from each class. At best, these studies provide a yardstick for judging whether or not each customer class is paying an appropriate share of the joint and common costs. The real question is whether the yardstick is reasonably straight and true, or whether it is bent to favor particular classes at the expense of others.

Aside from the long lags that typically occur between when costs are planned, contracted, and incurred and when those costs are recovered through rates, there is another fundamental problem. Most of the Company's embedded costs are not caused by the actions of particular customers or customer classes; rather they are incurred by management based upon an evaluation of the needs of the system as a whole. Thus it isn't feasible, or meaningful, to rely entirely on an evaluation of causal relationships in deciding on the most reasonable allocation method.

Consider, for example, an investment in which 10% of the cost can be meaningfully traced to customer classes and the remaining 90% is attributable to factors like fluctuations in the weather and fundamental characteristics of the geography of the Company's service territory. It is not necessarily reasonable to allocate 100% of the investment solely on the basis of the 10% that is logically traceable to customers. Furthermore, given the impossibility of identifying and measuring causative factors precisely, even this 10% of the total cost might be misinterpreted and traced to the wrong classes.

In evaluating the relative merits of different approaches, I believe it is important for the Commission to give adequate recognition to the basic product being sold by UNSE: electrical energy. Any allocation method that slights the importance of the most fundamental measure of the Company's output (kilowatt hours of electricity) should be viewed with skepticism. Where there is no clear cause-and-effect relationship between customer actions and costs, kWh sales provides a reasonable basis for allocation, because they closely reflect the benefits received by each class from the investments and expenses in question.

Q. Would you briefly explain the Average and Peaks allocation approach?

A. Yes. There are several ways this approach can be implemented, but in general it gives partial weight to the "average" level of demand, and some weight to a measure of "peak" demand.

Consider a simplified system consisting of four classes. As shown on Schedule BJ-15, Class A has a 50 kW load that runs at all times. Class B has a maximum load of 100 kW, and a load factor of 50%; it does not operate during the system coincident peak hours. Class C is similar, with a maximum load of 100 kW, and a load factor of 50%; however, 75kW of its load is present when the system coincident peaks occur. Finally, Class D has a 25% load factor; its coincident peak load is 150kW, and its non-coincident peak (NCP) is 200kW. The system CP demand in this example equals 275 kW and the sum of the NCP demands equals 450 kW. The average demand would equal 50 kW in each case, with the system average demand totaling 200kW.

There are several different versions of the coincident peak component. All of these methods allocate costs based on participation in system-wide coincident peaks. That is, during the hours when the system reaches its greatest demand, each load's portion of that demand is determined, and this becomes the basis for allocation. One method focuses on the hour during each month in which the maximum level of demand is experienced, then averages the results of these 12 different hours. This is sometimes referred to as a "12 CP" method. When this logic is taken to the extreme, it focuses on the single hour during the year when the highest CP is experienced. This is called the "1 CP" method. Anther variant is the "2 CP" method, which typically focuses on the maximum summer hour, and the maximum winter hour, whenever those happen to occur. UNSE uses the 4CP method, which is similar to the 1 CP method, except that it focuses exclusively on the four summer months, rather than the single hottest month; no consideration is given to peak characteristics during any other months of the year.

From an economic standpoint it is apparent a utility does not design its generating system or negotiate purchased power contracts merely to meet the coincident peak demand, regardless of whether one focuses on 1, 2, 3, 4, or 12 hours of each year. Yet, this is the underlying basis of the various CP allocation methods. In reality, when designing the system or negotiating power purchases, management is also concerned with system reliability, fuel costs, and the ability to obtain all of the energy required to meet its customers' needs, as well as the riskiness and cost-effectiveness of the method used to acquire the needed power, including questions of fuel diversity, transmission costs required to move power from the point of generation to the point of consumption, and related geographic characteristics.

Q. Do you agree with the Company's use of the Average and Peaks method?

A. In general, this is a far better approach than a purely peak-oriented methodology, as is sometimes advocated by other parties. The Average and Peaks method recognizes that the primary purpose of a utility's production plant is to provide energy used by its customers, and thus it gives considerable weight to energy (average demand). However, the Average and Peaks approach also recognizes that it is less costly to serve customers with high load factors (their use of energy occurs fairly uniformly throughout the day, 365 days a year), and customers who consume little or no energy during times when energy use is at a peak (e.g. street lighting, which occurs in the evening). These types of customers are allocated a relatively small share of the cost of production plant, while customers with loads that fluctuate in synch with the system are allocated a somewhat higher share. Logically, both average demand and UNSE's system coincident peak would both be factors considered in determining the price paid by UNSE for purchased power – regardless of whether the price of that power is stated purely on a per-KWH basis.

To the extent a cost allocation method is supposed to reflect the factors which "cause" costs, it makes sense to give some consideration to coincident peak data, as well as average demand, or energy. Nevertheless, it is also fair to say that the inherent problems with cost allocation studies are particularly acute in this case, where very little of UNSE's power is self generated. While pricing of the power purchase contracts may provide some insight into the underlying cost patterns, they are not fully determinative. For instance, prices can be stated on a flat per-KWH basis, yet the stated price per KWH may be influenced, in part, by the Company's average load factor, as historically observed and expected to occur in the future.

IV. Revenue Distribution

Q. Let's turn to the fourth section of your testimony. What factors do you think should be considered in developing the interclass revenue distribution?

A. I recommend giving some consideration to the cost of service results. However, I think other factors are also important in developing a fair and reasonable revenue distribution, including historical rate relationships, ability to pay, relative risk, and demand or market conditions (including the extent of any retail competition that might exist).

It is sometimes argued that the revenue burden should be distributed among the classes based entirely upon the results of a particular class cost-of-service study, at least as a goal. This argument has grown in popularity as "cost-based" ratemaking has come into vogue. However, I fundamentally disagree with this philosophy, particularly when it is tied to a single embedded cost allocation study. Valid cost-of-service studies can provide a useful starting point in developing the overall revenue distribution; but even if the cost study itself isn't controversial, the ultimate determination of rate spread should be tempered by consideration of other factors, such as the ones I just enumerated.

Any proposal to move away from the existing rate relationships should be implemented gradually. This is particularly important in a case like the present one, where the cost allocation methods are a matter of controversy, changes in the allocation methods are being proposed by various parties, and there is relatively little information available to evaluate how the various allocation methods react to changing weather and economic conditions, and thus little is known about how the various class returns react to changing conditions in the future.

In any event, the revenue distribution should not be designed merely to track the results of a particular cost-of-service study. Instead, thought should be given from the outset to the potential hardships imposed on particular classes, historical relationships among the classes, and other elements of interclass equity. Moreover, the Commission should recognize that efforts to achieve uniform class rates of return are mostly fruitless. Even if a consistent COS methodology is employed from case to case, minor fluctuations in weather, economic conditions, and other variables can easily produce absolute fluctuations in the class rates of return of 1%-4% or even more, defeating such an attempt at uniformity. If an above-average increase is imposed in one case (because a class appears to earning less than the average return), a below-average increase may appear appropriate in the very next case, simply because of minor fluctuations in weather or usage patterns – even if the underlying methodology is not changing. Of course, where changes in the costing methodology are involved, the class returns can fluctuate by even wider margins, due simply to differences in allocation techniques.

Given the inherent instability and subjectivity of the various allocations, the goal of absolute uniformity in class rates of return can probably never be achieved. Such an effort is an attempt to hit a moving target, and that very effort can potentially conflict with important policy objectives, like rate continuity, gradualism and stability.

Q. How has the Company proposed to distribute its proposed revenue increase among the various customer classes?

A. The Company explains that the goal of its cost of service study

is to confirm the extent to which present and proposed rates generate

> revenue that recovers costs and provides for a reasonable return on investment per customer class. ... If the proposed rates produce class revenues resulting in each class earning its required return on invested capital, we say that "parity" has been reached.". [Id., pp. 17-18]

Of course, this goal of "parity" or uniformity is mathematically dependent on the specific allocation procedures used in the cost study. If different allocations were used, the proposed revenue distribution would also likely change.

Q. Did the Company seek to achieve parity in its rate design?

A. No. UNSE explains:

> The impact on customers must be weighed against the benefits of moving to costbased rates. The Company's approach promotes "gradualism." It avoids large percentage differences in class revenue increases. In other words, we balanced the future need to move each class towards rates that are more reflective of cost of service while recognizing that such a move must be tempered with other factors like gradualism, and the avoidance of "rate shock". [Id., p. 18]

The following table shows UNSE's estimated rates of return by customer class associated with the Company's current rates and proposed rates, based on the Company's proposed revenue requirement analysis, and proposed cost allocations, and assuming BMGS is added to rate base. Also shown are the proposed revenue changes as a percentage of adjusted test year revenues. Returns under proposed rates range from a low of -26.25% for the Lighting class to a high of 17.15% for the Large General Service class.

Class	Return Present Rates	Return Proposed Rates	Revenue Change
Residential:	3.43%	4.45%	7.75%
Small General Service:	7.35%	12.04%	9.21%
Large General Service:	10.19%	17.15%	9.21%
Large Power Service:	-1.40%	-2.25%	9.21%
Interruptible Power Service:	1.19%	3.22%	9.21%
Lighting:	-14.14%	-26.25%	9.21%
Total:	4.77%	7.29%	8.48%

Source: Schedules BMGS G-1, G-2, H-1
Note: Residential revenue change includes reduced CAREs revenues

Q. What is your reaction to UNSE's proposed revenue distribution?

A. The Company has essentially proposed a uniform across-the-board percentage increase in rates. In my view this is a reasonable approach to use. Nevertheless, moderate deviations from the average increase would also be reasonable, and consistent with the principle of rate stability and gradualism.

For the reasons I stated earlier, I don't believe the Company's cost allocation should be the sole consideration in developing rates; but, neither do I think it needs to be completely ignored. Instead, it would be reasonable to give modest weight to the cost study results – particularly when the class return is far above or below the system average.

The Company's cost allocation study shows three classes have significantly below-average returns: Large Power Service, Interruptible Power Service, and Lighting. The study indicates one class – Large General Service – has a significantly above-average return. Neither of the other classes have returns that deviate greatly from the system average. The Residential class return is a little below the average, while the Small General Service return is a little above the average. In this regard, it's important to realize that the Residential return includes the full impact of the CARES discount, which distorts the result. This discount is appropriately considered a cost to be borne by all customer classes – not just the Residential class, as assumed in the Company's study.

Q. Have you developed an alternative revenue distribution approach which you are recommending for the Commission to consider?

A. Yes. I have developed an alternative methodology which gives considerable weight to historic rate relationships, while also giving some consideration to the Company's cost of service results.

Specifically, starting with the results of the Company's cost of service study, I looked at the classes with rates of return significantly above or below the system average. In order to avoid inter-class inequities, and in recognition of the fact that cost allocation studies are not perfectly precise, I believe that none of the classes should receive percentage rate increases that differ dramatically from the overall system average. Instead, I recommend increasing the rates paid by these classes by slightly more, or less, than the system average (as appropriate), thereby moving the class returns toward the average, without making futile attempt to move toward complete uniformity of returns. My specific recommendations are as follows:

First, I recommend giving an above-increase to the following rate schedules, which all have returns that are substantially lower than the system average (4.77%): Large Power Service (-1.40%), Interruptible Power Service (1.19%), and Lighting (-14.14%). In all of these cases, the Company's cost allocation study confirms these rate schedules are generating below-average returns (although the extent of the discrepancy isn't necessarily the same in each case). More specifically, I recommend increasing Large Power Service, Interruptible Power Service and Lighting by 1.0% more than the Residential and Small General Service classes.

Second, Large General Power has a return that is substantially higher than the system average; I recommend increasing the rates paid by this class by 1.0% less than the Residential and Small General Service classes.

Third, the Residential and Small General Service classes have returns that are relatively similar to the system average, and thus there is no need to take steps to either increase or decrease their overall position in the COSS. While I have not developed exact calculations, I estimate that these classes would receive an increase of approximately 3.4% if RUCO's revenue requirement were adopted, while Large Power Service, Interruptible Power Service and Lighting would increase by approximately 4.4% and Large General Power would increase by approximately 2.4%.

V.Residential Rate Design and Miscellaneous Tariff Issues

Q. Let's turn to the last section of your testimony. What other rate design issues do you wish to discuss?

A. I would like to comment on the Company's proposals regarding customer charges, time of use (TOU) rates, and rates for low income customers. Also, I would like to address UNSE's inclining block energy charges.

Q. Let's discuss customer charges. Can you describe the existing charges?

A. The current customer charge for residential customers is $7.50. Customer charges for other customer classes range from $4.12 for Lighting, to $400.00 for Large Power Service >69KV.

Q. What is UNSE proposing with regard these charges?

A. The Company is proposing to increase these charges for all classes (excluding CAREs) "to levels closer to the cost-based levels indicated in the Class Cost of Service Study". [Erdwurm Direct, p. 20] As shown in the table below, the increases range from 1.75% for Large Power

Service >69KV, to 10.07% for Lighting. Residential customers would see a 6.67% increase in their customer charge.

Class	Current Customer Charge	Proposed Customer Charge	Percent Change
Residential:	$7.50	$8.00	6.67%
Residential CARES:	$7.50	$3.50	-53.33%
Small General Service:	$12.00	$12.50	4.17%
Large General Service:	$15.50	$16.00	3.23%
Large General Service TOU:	$20.40	$20.90	2.45%
Large Power Service (<69KV):	$365.00	$372.00	1.92%
Large Power Service (>69KV):	$400.00	$407.00	1.75%
Interruptible Power Service:	$15.50	$16.00	3.23%
Lighting:	$4.12	$4.54	10.07%

Source: Schedule H-3

Q. What is the basis for these increases?

A. As I mentioned, the primary justification for this proposal is UNSE's belief that this will move rates closer to the costs indicated by its cost of service study. Consistent with this reasoning, according to the Company, the increases will also

> reduce how much high-use customers subsidize lower-use customers for the costs of metering, meter reading, billing, and other customer-specific equipment installed on the customers' premises.... [and move] a step towards providing more incentive for encouraging energy efficiency programs because the revenue requirement is less dependent on customers consuming electricity. [Id.]

Q. Do you agree with UNSE's customer charge proposal?

A. No. Many of the customer charges are already higher than appropriate; no further increases are warranted, and it would be preferable to shift away from this revenue source toward higher kWh rates. When customer charges are set at reasonable levels, they are an acceptable rate-design tool for recovering a portion of a regulated utility's costs. However, the Company's proposed customer charges are excessive. The proposed charges are not justified by cost considerations, and approving them would be inconsistent with such important policy objectives as economic efficiency, energy conservation, and equity.

I find several problems with the Company's proposal. First, holding all else constant, raising customer charges will tend to encourage kWh consumption and discourage energy conservation, while lowering customer charges will discourage energy usage and encourage greater energy efficiency.

Second, the proposed changes would place a heavier burden on low use customers, for whom this is a major element of their electric bill, including those who do not own a large number of appliances, those who set the thermostat at a high level during the summer, or otherwise find ways to use relatively little electricity.

Third, the Company's proposal is based upon a cost allocation approach which allocates substantial portions of the Company's distribution investment and operating expenses on the basis of customers, regardless of whether or not these items directly vary in response to decisions by customers to join or leave the system. Even if one were to assume that there is no better way to assign some of these costs that doesn't mean the resulting allocated cost figures are a valid justification for determining what portion of the revenue requirement should be recovered through a fixed monthly charge, and what portion should be recovered through the kWh rates. Allocation techniques acceptable for interclass purposes are not necessarily optimal for intraclass rate design purposes.

Q. Would you elaborate on your first point?

A. Yes. Customer charges have a negative effect similar to that of declining block rates, in which rates drop as the level of usage increases. In general, such rate structures make small-volume users pay a higher average rate per kWh than large-volume users and tend to present customers with a relatively low kWh rate for increased usage. This has several undesirable effects: it imposes excessive rates on low-volume users, including those who are most successful in limiting their energy usage, and it tends to discourage energy conservation. A relatively high customer charge translates into relatively low kWh rates; as a result, it sends price signals that make it appear less costly to consume additional energy, providing relatively little reward for those customers who buy more efficient light bulbs or appliances, install additional insulation, adjust the thermostat to higher levels in the summer, or take other steps to reduce their consumption of electricity.

Although the Company's inclining block rates for energy charges ameliorates this problem, high customer charges tend to offset some of the benefits of the inclining block design. The following example in the table below illustrates this point. The costs are based on the Company's proposed residential rates, which include an $8.00 customer charge, an energy charge of $0.026115 per kWh for the first 400 kWhs and $0.036129 for each additional kWh, and a base power supply charge of $0.0687657 per kWh.

	200 kWh	500 kWh	1000 kWh
Customer Charge	$8.00	$8.00	$8.00
Energy Charge	3.22	14.06	32.12
Base Charge	13.75	34.38	68.77
Total	$24.97	$56.44	$108.89
Total per kWh	$0.125	$0.113	$0.109

Source: Schedule H-3-BMGS

As shown, a customer using 200 kWh during a given month would incur a total bill of $24.97 under the proposed rates. Thus, he would pay an average of about 12.5 cents per kWh. In comparison, a customer who uses 500 kWh would pay an average price of approximately 11.3

cents per kWh, or roughly 10% less than the rate per kWh paid by the smaller customer – just the opposite of what one would expect considering the inclining block rate design alone. Similarly, the customer using 1,000 kWh will actually pay less per kWh than the customer using 500 kWh, notwithstanding the use of an inclining block rate structure. In essence, a high customer charge tends to create an effective discount on the average rate per kWh paid by large-volume users relative to the rate paid by low volume users, and it confronts customers with a marginal price which is lower than would be the case if a lower customer charge were applied. In my view, this pricing pattern runs directly counter to the policy goal of encouraging energy conservation, and this disadvantage outweighs any putative benefit of better tracking allocating costs.

Q. Have you analyzed the methods by which the Company allocates costs to the customer charge?

A. Yes. I have reviewed the Company's cost of service study, and concluded that most of the costs allocated to this rate are not focused on the variable or marginal costs that are actually attributable to the decision of customers to join or leave the system. The customer charge should primarily collect the variable costs of metering, billing, and collecting the monthly bill. Other so called "customer costs" can and should be recovered through per kWh rates.

Q. Have you provided an alternative estimate of customer-related costs?

A. Yes. As shown on BJ-11, I have used the information provided in UNSE Schedules G-4 and H-2 to develop an alternative estimate of the costs that can form the basis of a more appropriate customer charge. I started with the group of expense accounts that the Company labels as "Customer Accounts" and "Customer Service & Info Exp" in its cost of service study, as listed on page 5 of BMGS Schedule G-4. Then, I removed certain accounts that clearly do not vary with the number of customers on the system each month. Specifically, I excluded the expenses in accounts 904 - "Uncollectible Accounts" and 431 - "Customer Deposit Interest"; the former account would more appropriately be allocated in proportion to revenue, or it could be directly assigned to individual classes in proportion to their actual uncollectible experience. The latter account is more appropriately allocated on a composite basis, in proportion to net plant or some other aggregate measure of the Company's investment, since customer deposits are a source of funding which can be used for general corporate purposes, like short term debt.

After removing these two accounts, the remaining expenses were then divided by the weighted number of customers, as developed by the Company on BMGS Schedule H-2, and the quotient was divided by 12 to arrive at a per-month cost. I'm not suggesting that rates need to be set exactly equal to this measure of costs, but I recommend the Commission start reducing the customer charges, rather than increasing them. The cost estimates set forth on BJ-11 can be used as an initial guide in making this transition. For example, the monthly customer cost for residential customers is $3.63, and I recommend reducing the customer charge for residential customers from the current level of $7.50, to $5.00 per month. The reduction in revenue resulting from this reduction in the customer charge would be offset by an increase in revenue from higher per-kWh rates. I plan to provide the Commission with a chart showing the effect of this proposal on some typical customer bills prior to the hearing in this case.

Q. Even if the Commission were to accept UNSE's cost allocations, which include an allocation of various investment-related costs, do you nevertheless oppose recovery of those costs through monthly customer charges?

A. Yes. Neither economics nor public policy requires that electric rates be tied directly to the results of fully allocated cost-of-service studies. Such studies are useful primarily as a tool which can assist regulators in determining the appropriate distribution of revenues among customer classes. Even in that context, factors other than the cost study results should be considered. Furthermore, in designing rates within the various rate classes, fully allocated embedded cost studies are of relatively little value.

Class cost of service studies are too imprecise to accurately reflect cost differences between individual customers, or between customers with different demographic, usage and other characteristics. Furthermore, attempts to design rates based upon the results of an embedded cost study can conflict with important public policy objectives. Two long-recognized policy goals pertinent to electricity rate design are the promotion of economic efficiency and the encouragement of energy conservation. The former objective implies that consumers should pay rates that reflect the costs they impose on society for the electricity they consume. Viewed strictly from the Company's perspective, these costs would include any production, transmission, distribution, and other costs (including fuel) that vary as a function of consumption.

A fully-allocated cost study does not produce that kind of cost result, because it includes not only costs that vary with consumption, but also all of the fixed costs incurred by the Company regardless of what customers (and potential customers) do. Thus these studies do not show the cost caused by a customer's decision to join or remain on the grid, nor do they show the costs which are caused by the customer's decisions regarding how much electricity to consume during a particular month, nor do they accurately reflect the costs which determined by the customers decisions concerning when to consume power (e.g. during peak hours). To the extent the Commission is persuaded that cost data may be helpful in advancing goals like economic efficiency and energy conservation, fully allocated embedded costs are not particularly useful.

In fact, a marginal cost study better isolates costs which are directly affected by consumer decisions, and marginal cost data is much more useful in evaluating the Company's current and proposed rates against the goal of economic efficiency. Of course, rates set equal to marginal costs may result in overrecovery or underrecovery of a utility's revenue requirement, and I am not suggesting that marginal cost studies are a panacea. My point is simply to emphasize that fully-allocated costs are not the same as marginal costs, and designing prices to track such costs will not necessarily promote economic efficiency, because allocated embedded costs are not directly related to specific production and consumption decisions.

Likewise, rates tied directly to the results of fully allocated class cost-of-service studies may not promote the longstanding goal of energy conservation. Strictly speaking, conservation will be encouraged by setting a relatively high price per kWh – even if that means setting a customer charge which is below the level of customer costs. More generally, energy conservation is encouraged when customers are sent a price signal which reflects the relatively high cost of adding new generating and transmission capacity, and which reflects the relatively high cost of producing electricity without harming the environment. Price signals of this sort are not likely to be derived from an embedded cost of service study, which gives great weight to various fixed and sunk costs, and gives relatively little weight to the forward looking costs to society which are of such concern to environmentalists, and others who advocate energy conservation.

In this case, the Company's proposed increases to the fixed monthly component of its rates results in a reduction in the level of kWh rates which would otherwise be applicable. Decreases in the energy charge which are offset by increases in the customer charge tend to encourage energy consumption rather than promote energy conservation. Hence, regardless of how one feels about the use of embedded cost analyses, the Company's proposed customer charge increases are inconsistent with valid public policy objectives, and should not be accepted.

Q. Let's discuss time of use rates. Can you please describe the Company's existing rates?

A. UNSE has five voluntary TOU plans:

- Residential Weekends Off-peak - RES-01 -TOU-A
- Small General Service - SGS-10 TOU
- Large Power Service - LPS-TOU
- Large General Service - LGS-TOU-N; and
- Interruptible Power Service - IPS-TOU

Each of these TOU plans has Summer on-peak, shoulder and off-peak pricing, and winter on-peak and off-peak pricing. For residential customers, all weekend hours (and all hours for six selected holidays) are Off-peak. [Erdwurm Direct, p. 21]

Q. What changes is the Company proposing with regard to its TOU rates?

A. First, UNSE proposes to redesign its TOU rates by greatly increasing the rate differential between the on and off-peak time-periods. BJ-12 shows the On-Peak, Shoulder, and Off-Peak Summer rates, and the On-Peak and Off-Peak Winter rates for each TOU plan. As shown, current Summer Off-Peak rates are approximately 79-84% of Summer On-Peak rates. Winter Off-Peak rates are approximately 76-81% of Winter On-Peak rates. Under the Company's proposal, the differentials would be dramatically widened, so that Summer Off-Peak rates would be just 31-39% of Summer On-Peak rates, and Winter Off-Peak rates would be approximately 23-24% of Winter On-Peak rates. For residential customers specifically, Summer Off-Peak rates would go from 83.73% to 31.43% of the Summer On-Peak rates, and Winter Off-Peak rates would go from 81.45% to 23.42% of the Winter On-Peak rates.

The Summer On-Peak period is 2:OO p.m. to 6:OO p.m. and Summer Shoulder Periods are Noon (12:OO p.m.) to 2:OO p.m. and 6:OO p.m. to 8:OO p.m. The Winter On-Peak Periods are 6:OO a.m. to 1O:OO a.m. and 5:OO p.m. to 9:00 p.m. All other Summer hours are Off-peak. Weekend and holiday hours are also off-peak for residential customers. For other customer classes, the TOU hour designation applies every day. [Id.] UNSE claims two benefits to the increased differentials. First,

> [L]arger price differentials between On-Peak, Shoulder-Peak and Off-peak periods mean customers will see a bigger gap between the price they pay for On-Peak power as compared to Shoulder-Peak or Off-peak power. This will provide an enhanced incentive to shift load to off-peak periods. In other words, larger differentials increase the relative price of on-peak service and decrease the price of off-peak service. This should lead to more customers using less energy at peak times, and "shifting" the demand or load to other times in the day. By shifting load to off-peak periods, this helps reduce the need for UNS Electric to find capacity during peak times when that capacity is most expensive and is also in the shortest supply. So, larger differentials should ease the burden on the Company to acquire the most costly power during these peak periods. [Id., p. 23]

UNSE also claims that current TOU customers can save even more money under these increased differentials, and offers the following example:

> Consider, for example, an average residential customer who is able to shift 30% of summer peak usage to summer shoulder, 25% of summer shoulder to summer off-peak, and 20% of winter peak usage to winter off-peak. This customer would save 5.1% annually under the proposed time-of-use design. That is over 2.5 times more than the 1.9% annual savings to be realized under the current TOU tariffs. [Id.]

Second, UNSE proposes to implement Super-Peak Demand Response rates for residential customers, and for general service customers with demands less than 3MW. [Id., p. 26] This rate design applies a significantly higher rate for 1 hour each day (excluding weekends and selected holidays) during the summer, with lower rates during the remaining hours. UNSE's proposed Super Peak rates are shown on BJ-13.

Q. What is your response to the Company's residential TOU proposals?

A. In general, the Company is to be commended for offering customers TOU rate options, and I am sympathetic with its desire to increase participation on these schedules. As well, I'm sympathetic to its proposal to increase the time period differentials, which will encourage customers to reduce their on-peak consumption. However, further thought needs to be given to the appropriate differentials. The Company has offered very little evidence in support of the specific percentage differentials it is proposing, and due to time constraints I have not had the opportunity to evaluate this aspect of its proposals in depth.

Similarly, I believe the Company's "super-peak" proposal has merit, but I have some concerns regarding the specifics. I agree with the general philosophy behind these proposals; to the extent certain customers are willing to reduce their usage during peak hours, the Company will be able to avoid the high costs associated with purchasing power on the spot market to meet peak loads, and it will reduce the need to add peaking capacity in the future. As well, improvements in the Company's system load factor may enable it to reduce the price it pays for purchased power, even when that power is purchased on a uniform price per kWh basis. In general, it is economically efficient to provide customers with price signals that recognize that on peak consumption is considerably more costly than off-peak consumption.

However, I have some concerns that the "super peak" pricing proposal doesn't seem to go far enough in aligning price signals with actual costs. For instance, the Company appears to be proposing to apply the higher price every Summer weekday, regardless of the weather, and regardless of whether or not unusually high costs will be incurred during that particular day. The UNSE proposal is somewhat ambiguous, simply stating: "The single hour chosen will start at either 2:OO p.m., 3:OO p.m., 4:OO p.m. or 5:OO p.m. for summer months". [Id., p. 25] It isn't entirely clear when this hour will be chosen, or by whom. If customers have the freedom to select the hour when they can most easily reduce their load, and to specify this choice when they sign up for the service, this approach may be quite appealing to customers. Yet, I'm not sure if this is the Company's intent, since it needs to be concerned about adverse selection and a lack of load diversity amongst the super peak customers – particularly if large numbers of customers opt into this rate. It wouldn't be desirable to have large numbers of customers all selecting the same exact hour, leading to load reductions during one particular peak hour, without reducing load in any of the adjacent hours.

If the Company wants to limit the number of customers who can sign up for any specific super peak hour, additional tariff language will be needed to ensure that customers are given an opportunity to join a waiting list for their preferred hour, and to ensure that any decision by the Company to assign customers to an hour other than their preferred choice will be made in a reasonable and non-discriminatory manner.

Q. Do you have any other suggestions for a more precisely targeted version of the Super Peak pricing concept?

A. Yes. I recommend the Company develop, and the Commission approve as a pilot program an alternative approach to super peak pricing which is more precisely targeted. In this pilot program, the Company would have considerable flexibility to identify super peak hours based on actual load conditions on a day to day basis throughout the hot Summer months. In return, customers would receive a deeper discount on their off-peak consumption. The goal would be to more precisely target the actual peak hour, based on anticipated weather and load conditions of each specific day.

To be fully effective, of course, customers would need to be informed of each "super peak" pricing period before it occurs, so that they have an opportunity to adjust their thermostats, avoid running their dishwasher or doing their laundry, or take other actions to reduce their load during the peak time period. While it is potentially difficult to contact a large number of customers on short notice, with today's technologies, it doesn't have to be costly to do this. If customers are contacted using a combination of emails, text messages and "robocalls" (recordings sent to the customer's telephone), a high percentage will receive advance notification of the peak period each day, and the per-customer cost would be minimal.

This alternative approach would make it possible to more narrowly focus the super-peak pricing period on specific hours and days when the Company incurs the highest costs - the *particular hours when the system is expected to* experience unusually high loads, limited generating capacity, or both. Most obviously, the super-peak price should apply during the hottest hours of the hottest days of each summer. Since weather is variable, it is impossible to predict these hours much more than 36 hours in advance; traditional time-of-day pricing is greatly over-simplified, since it applies the same high price during all of the summer afternoon hours, regardless of the actual weather. Similarly, the Company should have the flexibility to send the higher price signal during hours when its costs are unusually high because one of its peaking plants is unavoidably off-line, even if the weather isn't unusually hot.

Consistent with this reasoning, under this alternative approach, it would not be necessary to apply the "super peak" price to a specific hour of every single day of the entire summer. Instead, the higher rate would be limited to no more than 60 hours each summer, and no more than 2 hours during any single day, while the Company would have flexibility in choosing specific hours and days on a case-by-case basis.

Under this alternative approach, as I envision it, the Company would not be required to charge every customer the higher super peak price during the exact same hour each time. Instead, it would have the flexibility to maximize system benefits and cost savings, by adjusting the super peak hour on a case-by-case basis, while offering a larger off-peak discount, to ensure the plan is still attractive to customers. For instance, on unusually high-cost days, the Company could apply the higher price from 2pm until 4pm for one group of customers (the "A" group), while applying the higher price from 3pm until 5pm for a second group of customers (the "B" group). This would significantly increase the overall load reduction throughout that entire 3 hour period, with the maximum reduction occurring during the hour with the highest anticipated peak. The idea is to provide the Company with greater flexibility to focus the price signal during the specific days of each year when it receive the greatest benefit from the load reduction, while still providing reasonable limits on the frequency with which the higher rate would apply (no more than two hours per day and no more than 60 hours per year), thereby making the rate attractive to customers.

Q. Can you now explain the Company's low income proposals?

A. First, UNSE proposes to shield the majority of CAREs customers from the rate increase proposed in this case.

> CARES customers with monthly usage of 945 kWh will receive the full benefit of the bill reductions attributable to the June 1,2009 downward adjustment in the PPFAC rate, but will not see increases attributable to UNS Electric's proposed rate increase in this case. The 945 kWh threshold exceeds CARES median use of 621 kWh per month and CARES average use of 772 kWh per month. ... As a CARES customer's usage passes 945 kWh and continues to grow, this customer will face relatively more exposure to the rate increase, which is appropriate given the Company's conservation objectives.[Erdwurm Direct, pp. 4-5]

UNSE proposes to accomplish this through the combination of several rate proposals.

> This has been accomplished by lowering the CARES customer charge (before any applicable percentage discount) to $3.50 per month from the current level of $7.50 per month. Additionally, CARES customers will pay a reduced base power supply rate, and the PPFAC forward and true-up components will be set to zero and frozen for CARES customers upon implementation of new rates. CARES customers will also still receive the additional percentage discounts (30% for 0-300 kWh; 20% for 301-600 kWh, and 10% for 601-1000 kWh) and the flat $8.00 per month discount for customers with monthly usage in excess of 1,000 kWh. [Id., p. 28]

Q. Do you agree with this aspect of the Company's rate design proposals?

A. I agree with the general goal of ameliorating the impact of any rate increase on CAREs customers. Needless to say, I also agree with the proposal to reduce the CAREs customer charge, since I am recommending this rate element be reduced for other customers, as well. As I explained above, I developed an estimate of $3.63 per month for customer costs, and recommend reducing the customer charge from $7.50 to $5.00. Consistent with that recommendation, it would be reasonable to further reduce the customer charge paid by CAREs customers to $2.50. However, some of the other proposals, like modifying the base power supply rate and PPFAC true-up mechanism, seem unnecessarily complicated.

Instead, I would recommend increasing the usage-based discounts; this is a simpler approach, which still ameliorates the impact on CAREs customers, yet it also makes it easier to balance the policy tradeoffs related to energy conservation. By focusing on the discount percentages, the Commission can adjust how much of the CAREs rate relief benefits low usage customers, and how much benefits higher usage customers. By increasing the discount applicable to the customer charge and low kWh blocks, it is feasible to provide substantial rate relief to CAREs customers, without reducing the incentive for these customers to conserve energy.

Q. What else is the Company proposing with regard to CAREs customers?

A. UNSE proposes to expand the range of qualifying customers, but only if the costs are borne by other customers. Currently eligible customers include those within 150% of the poverty threshold.

> UNS Electric encourages the Commission to offer a program that provides discounts to customers falling between the 150% and the

> 200% of poverty thresholds. However, UNS Electric's support of an expanded program is contingent upon the program costs being fully recovered from other retail customers. [Id., p. 29]

Q. Do you agree with this proposal?

A. No. Any income cut-off for inclusion in the CAREs plan is necessarily somewhat arbitrary. No justification has been provided for increasing the cut-off above the current level. Already, we have a situation where customers at 160% of the poverty level (and those customers who are unaware of the CAREs program, or decline to participate) are subsidizing those below 150% of the poverty level who are taking advantage of this discount. While expanding coverage to include customers at 160% of the poverty level eliminates this potential inequity for those customers, it exacerbates the problem for those above 200% of the poverty level. Why should customers at 200 to 250% of the poverty level subsidize those who are below 200% of the poverty level? By definition, neither the group of customers paying the subsidy, nor those receiving it, are poverty stricken, and neither group is as needy as those below 150% of the poverty level.

I am troubled by the lack of any solid justification for increasing the cutoff to 200%, but I am also deeply concerned by the practical implications of this proposal, however well-intentioned. As the cutoff is increased farther and farther above the poverty level, a larger and larger number of customers will become eligible for the subsidy – which will significantly increase the burden on other customers, who will have to pay a subsidy to a substantially larger number of customers. In this regard, it is important to realize that the current difficult economic difficulties have had adversely affected many different types of customers, including middle class, two earner families where one of the family members has lost their job, but remain above 200% of the poverty line. It is not at all clear that someone who is undergoing genuine hardship during these difficult economic times should subsidize someone else, merely because the latter customer happens to have an income level falling between 150% and 200% of the poverty level. Finally, I would note that the 150% cutoff has been used by many, if not all, of the other utilities in Arizona, and no evidence has been offered suggesting that this cutoff has not been a reasonable and successful solution to the difficult policy tradeoffs that I mentioned a moment ago.

Q. Finally, can you briefly discuss the Company's "inclining block" energy charges?

A. Yes. In its prior rate case, UNSE proposed an inclining block rate structure for residential and small general service customers. [See, Decision 70360, p. 52] The Company proposed to apply a one cent per kWh discount for the first 400 kWh of usage, compared to the second block for all usage over 400 kWh. [Id.] The Commission held:

> We agree with the parties that an inverted block rate structure sends a strong and important price signal to customers to conserve energy. While we recognize Staffs concern that some customers will receive a rate decrease while other customers receive a rate increase, the public policy behind incenting conservation outweighs the concerns raised by Staff. We will approve UNSE's inverted block rate design as supported by all parties but Staff. [Id.]

Q. Is the Company proposing any changes to this rate structure?

A. No. However, I believe it would be appropriate to make some changes, to build upon the progress that was made in the last case. More specifically, I suggest adopting a block structure like the one that is currently included in APS's tariff. APS currently has rate blocks: the first 400 kWh has the lowest rate; the second 400 kWh has a higher rate; and, all additional kWh have a still higher rate. Consistent with that pattern, and as a logical extension of the policy adopted in the prior rate case, I recommend charging the lowest rate for the first 400 kWh;

charging one cent more for usage in the second 400 kWh block; and, charging one cent more (two cents higher than the first block) for all additional kWh.

Q. Does this conclude your rate design testimony pre-filed on November 13, 2009?

A. Yes, it does.

Appendix A

Qualifications

Present Occupation

Q. What is your present occupation?

A. I am a consulting economist and President of Ben Johnson Associates, Inc.®, a firm of economic and analytic consultants specializing in the area of public utility regulation.

Educational Background

Q. What is your educational background?

A. I graduated with honors from the University of South Florida with a Bachelor of Arts degree in Economics in March 1974. I earned a Master of Science degree in Economics at Florida State University in September 1977. The title of my Master's Thesis is a "A Critique of Economic Theory as Applied to the Regulated Firm." Finally, I graduated from Florida State University in April 1982 with the Ph.D. degree in Economics. The title of my doctoral dissertation is "Executive Compensation, Size, Profit, and Cost in the Electric Utility Industry."

Clients

Q. What types of clients employ your firm?

A Much of our work is performed on behalf of public agencies at every level of government involved in utility regulation. These agencies include state regulatory commissions, public counsels, attorneys general, and local governments, among others. We are also employed by various private organizations and firms, both regulated and unregulated. The diversity of our clientele is illustrated below.

Regulatory Commissions

Alabama Public Service Commission—Public Staff for Utility Consumer Protection
Alaska Public Utilities Commission
Arizona Corporation Commission
Arkansas Public Service Commission
Connecticut Department of Public Utility Control
District of Columbia Public Service Commission
Idaho Public Utilities Commission
Idaho State Tax Commission
Iowa Department of Revenue and Finance
Kansas State Corporation Commission
Maine Public Utilities Commission
Minnesota Department of Public Service
Missouri Public Service Commission
National Association of State Utility Consumer Advocates
Nevada Public Service Commission
New Hampshire Public Utilities Commission
North Carolina Utilities Commission—Public Staff
Oklahoma Corporation Commission
Ontario Ministry of Culture and Communications
Staff of the Delaware Public Service Commission
Staff of the Georgia Public Service Commission
Texas Public Utilities Commission
Virginia State Corporation Commission
Washington Utilities and Transportation Commission

West Virginia Public Service Commission—Division of Consumer Advocate

Wisconsin Public Service Commission

Wyoming Public Service Commission

Public Counsels

Arizona Residential Utility Consumers Office

Colorado Office of Consumer Counsel

Colorado Office of Consumer Services

Connecticut Consumer Counsel

District of Columbia Office of People's Counsel

Florida Public Counsel

Georgia Consumers' Utility Counsel

Hawaii Division of Consumer Advocacy

Illinois Small Business Utility Advocate Office

Indiana Office of the Utility Consumer Counselor

Iowa Consumer Advocate

Maryland Office of People's Counsel

Minnesota Office of Consumer Services

Missouri Public Counsel

New Hampshire Consumer Counsel

Ohio Consumer Counsel

Pennsylvania Office of Consumer Advocate

Utah Department of Business Regulation—Committee of Consumer Services

Attorneys General

Arkansas Attorney General

Florida Attorney General—Antitrust Division

Idaho Attorney General

Kentucky Attorney General

Michigan Attorney General

Minnesota Attorney General

Nevada Attorney General's Office of Advocate for Customers of Public Utilities

South Carolina Attorney General

Utah Attorney General

Virginia Attorney General

Washington Attorney General

Local Governments

City of Austin, TX

City of Corpus Christi, TX

City of Dallas, TX

City of El Paso, TX

City of Galveston, TX

City of Norfolk, VA

City of Phoenix, AZ

City of Richmond, VA

City of San Antonio, TX

City of Tucson, AZ

County of Augusta, VA

County of Henrico, VA

County of York, VA

Town of Ashland, VA

Town of Blacksburg, VA

Town of Pecos City, TX

Other Government Agencies

Canada—Department of Communications
Hillsborough County Property Appraiser
Provincial Governments of Canada
Sarasota County Property Appraiser
State of Florida—Department of General Services
United States Department of Justice—Antitrust Division
Utah State Tax Commission

Regulated Firms

Alabama Power Company
Americall LDC, Inc.
BC Rail
CommuniGroup
Florida Association of Concerned Telephone Companies, Inc.
LDDS Communications, Inc.
Louisiana/Mississippi Resellers Association
Madison County Telephone Company
Montana Power Company
Mountain View Telephone Company
Nevada Power Company
Network I, Inc.
North Carolina Long Distance Association
Northern Lights Public Utility
Otter Tail Power Company
Pan-Alberta Gas, Ltd.
Resort Village Utility, Inc.
South Carolina Long Distance Association

Stanton Telephone
Teleconnect Company
Tennessee Resellers' Association
Westel Telecommunications
Yelcot Telephone Company, Inc.

<u>Other Private Organizations</u>

Arizona Center for Law in the Public Interest
Black United Fund of New Jersey
Casco Bank and Trust
Coalition of Boise Water Customers
Colorado Energy Advocacy Office
East Maine Medical Center
Georgia Legal Services Program
Harris Corporation
Helca Mining Company
Idaho Small Timber Companies
Independent Energy Producers of Idaho
Interstate Securities Corporation
J.R. Simplot Company
Merrill Trust Company
MICRON Semiconductor, Inc.
Native American Rights Fund
PenBay Memorial Hospital
Rosebud Enterprises, Inc.
Skokomish Indian Tribe
State Farm Insurance Company
Twin Falls Canal Company
World Center for Birds of Prey

Prior Experience

Q. Before becoming a consultant, what was your employment experience?

A. From August 1975 to September 1977, I held the position of Senior Utility Analyst with Office of Public Counsel in Florida. From September 1974 until August 1975, I held the position of Economic Analyst with the same office. Prior to that time, I was employed by the law firm of Holland and Knight as a corporate legal assistant.

Q. In how many formal utility regulatory proceedings have you been involved?

A. As a result of my experience with the Florida Public Counsel and my work as a consulting economist, I have been actively involved in approximately 400 different formal regulatory proceedings concerning electric, telephone, natural gas, railroad, and water and sewer utilities.

Q. Have you done any independent research and analysis in the field of regulatory economics?

A. Yes, I have undertaken extensive research and analysis of various aspects of utility regulation. Many of the resulting reports were prepared for the internal use of the Florida Public Counsel. Others were prepared for use by the staff of the Florida Legislature and for submission to the Arizona Corporation Commission, the Florida Public Service Commission, the Canadian Department of Communications, and the Provincial Governments of Canada, among others. In addition, as I already mentioned, my Master's thesis concerned the theory of the regulated firm.

Q. Have you testified previously as an expert witness in the area of public utility regulation?

A. Yes. I have provided expert testimony on more than 250 occasions in proceedings before state courts, federal courts, and regulatory commissions throughout the United States and in Canada. I have presented or have pending expert testimony before 35 state commissions, the Interstate Commerce Commission, the Federal Communications Commission, the District of Columbia Public Service Commission, the Alberta, Canada Public Utilities Board, and the Ontario Ministry of Culture and Communication.

Q. What types of companies have you analyzed?

A. My work has involved more than 425 different telephone companies, covering the entire spectrum from AT&T Communications to Stanton Telephone, and more than 55 different electric utilities ranging in size from Texas Utilities Company to Savannah Electric and Power Company. I have also analyzed more than 30 other regulated firms, including water, sewer, natural gas, and railroad companies.

Teaching and Publications

Q. Have you ever lectured on the subject of regulatory economics?

A. Yes, I have lectured to undergraduate classes in economics at Florida State University on various subjects related to public utility regulation and economic theory. I have also addressed conferences and seminars sponsored by such institutions as the National Association of Regulatory Utility Commissioners (NARUC), the Marquette University College of Business Administration, the Utah Division of Public Utilities and the University of Utah, the Competitive Telecommunications Association (COMPTEL), the

International Association of Assessing Officers (IAAO), the Michigan State University Institute of Public Utilities, the National Association of State Utility Consumer Advocates (NASUCA), the Rural Electrification Administration (REA), North Carolina State University, and the National Society of Rate of Return Analysts.

Q. Have you published any articles concerning public utility regulation?

A. Yes, I have authored or co-authored the following articles and comments:

"Attrition: A Problem for Public Utilities—Comment." *Public Utilities Fortnightly*, March 2, 1978, pp. 32-33.

"The Attrition Problem: Underlying Causes and Regulatory Solutions." *Public Utilities Fortnightly*, March 2, 1978, pp. 17-20.

"The Dilemma in Mixing Competition with Regulation." *Public Utilities Fortnightly*, February 15, 1979, pp. 15-19.

"Cost Allocations: Limits, Problems, and Alternatives." *Public Utilities Fortnightly*, December 4, 1980, pp. 33-36.

"AT&T is Wrong." *The New York Times*, February 13, 1982, p. 19.

"Deregulation and Divestiture in a Changing Telecommunications Industry," with Sharon D. Thomas. *Public Utilities Fortnightly*, October 14, 1982, pp. 17-22.

"Is the Debt-Equity Spread Always Positive?" *Public Utilities Fortnightly,* November 25, 1982, pp. 7-8.

"Working Capital: An Evaluation of Alternative Approaches." *Electric Rate-Making,* December 1982/January 1983, pp. 36-39.

"The Staggers Rail Act of 1980: Deregulation Gone Awry," with Sharon D. Thomas. *West Virginia Law Review,* Coal Issue 1983, pp. 725-738.

"Bypassing the FCC: An Alternative Approach to Access Charges." *Public Utilities Fortnightly*, March 7, 1985, pp. 18-23.

"On the Results of the Telephone Network's Demise—Comment," with Sharon D. Thomas. *Public Utilities Fortnightly*, May 1, 1986, pp. 6-7.

"Universal Local Access Service Tariffs: An Alternative Approach to Access Charges." In *Public Utility Regulation in an Environment of Change,* edited by Patrick C. Mann and Harry M. Trebing, pp. 63-75. Proceedings of the Institute of Public Utilities Seventeenth Annual Conference. East Lansing, Michigan: Michigan State University Public Utilities Institute, 1987.

With E. Ray Canterbery. Review of *The Economics of Telecommunications: Theory and Policy* by John T. Wenders. *Southern Economic Journal* 54.2 (October 1987).

"The Marginal Costs of Subscriber Loops," A Paper Published in the Proceedings of the Symposia on Marginal Cost Techniques for Telephone Services. The National Regulatory Research Institute, July 15-19, 1990 and August 12-16, 1990.

With E. Ray Canterbery and Don Reading. "Cost Savings from Nuclear Regulatory Reform: An Econometric Model." *Southern Economic Journal,* January 1996.

Professional Memberships

Q. Do you belong to any professional societies?

A. Yes. I am a member of the American Economic Association.

UNS ELECTRIC, INC.
DOCKET NO. E-04204A-09-0206
TABLE OF CONTENTS TO BJ SCHEDULES

SCHEDULE #

UNS ELECTRIC, INC.
ALTERNATIVE CUSTOMER CHARGE CALCULATIONS

DOCKET NO. E-04204A-09-0206
SCHEDULE BJ-11

LINE NO.		(A) TOTAL	(B) RESIDENTIAL	(C) SGS	(D) LGS	(E) LPS	(F) INTERRUPTIBLE	(G) STREET LIGHTING
	CUSTOMER ACCOUNTS EXPENSES							
1	901-Supervision	$260,950	$198,177	$33,541	$15,296	$9,470	$259	$4,207
2	902-Meter Reading Expense	915,625	706,293	119,540	54,515	34,354	922	0
3	903-Cust Records & Coll Exp	3,070,993	2,327,967	394,009	179,683	113,233	3,039	53,063
4	905-Misc Cust Accts Exp	39,451	31,033	5,252	2,395	23	41	707
5	Total Customer Accts Expense	$4,287,019	$3,263,469	$552,343	$251,889	$157,080	$4,261	$57,977
	CUSTOMER SERVICE & INFO EXP							
6	908-Customer Assistance Exp	94,671	75,830	12,834	5,853	55	99	0
7	909-Info & Instruct Exp	49,423	39,587	6,700	3,055	29	52	0
8	910-Mlisc Cust Serv & Iinfo Exp	31,336	25,100	4,248	1,937	18	33	0
9	Total Cust Service & Iinfo Expense	$175,431	$140,517	$23,782	$10,846	$103	$183	$0
10	Customer Costs	$4,462,450	$3,403,986	$576,125	$262,735	$157,182	$4,444	$57,977
11	Adjusted Average Number of Customers	89,746	78,124	7,776	2,010	19	34	1,781
12	Customer Charge (Line 10/Line 11)/12	$4.14	$3.63	$6.17	$10.89	$689.40	$10.89	$2.71

<u>REFERENCES:</u>
UNSE BMGS Schedules H-2; G-4

UNS ELECTRIC, INC.
PROPOSED TOU RATES

DOCKET NO. E-04204A-09-0206
SCHEDULE BJ-12

LINE NO.		(A) Existing Rate	(B) Percent of On Peak	(C) Proposed Rate	(D) Percent of On Peak
	Residential TOU				
1	Summer on-peak	$0.092183	100.00%	$0.153093	100.00%
2	Summer Shoulder	$0.081803	88.74%	$0.068767	44.92%
3	Summer off-peak	$0.077183	83.73%	$0.048113	31.43%
4	Winter on-peak	$0.080873	100.00%	$0.153093	100.00%
5	Winter off-peak	$0.065873	81.45%	$0.035849	23.42%
	Small General Service TOU				
6	Summer on-peak	$0.090348	100.00%	$0.130888	100.00%
7	Summer Shoulder	$0.079658	88.17%	$0.066778	51.02%
8	Summer off-peak	$0.075348	83.40%	$0.040888	31.24%
9	Winter on-peak	$0.079448	100.00%	$0.130888	100.00%
10	Winter off-peak	$0.064448	81.12%	$0.032668	24.96%
	Large General Service TOU				
11	Summer on-peak	$0.082832	100.00%	$0.116024	100.00%
12	Summer Shoulder	$0.071452	86.26%	$0.059129	50.96%
13	Summer off-peak	$0.067832	81.89%	$0.041024	35.36%
14	Winter on-peak	$0.071072	100.00%	$0.116024	100.00%
15	Winter off-peak	$0.056072	78.89%	$0.027306	23.53%
	Large Power Service TOU				
16	Summer on-peak	$0.070170	100.00%	$0.094919	100.00%
17	Summer Shoulder	$0.058180	82.91%	$0.046959	49.47%
18	Summer off-peak	$0.055170	78.62%	$0.034919	36.79%
19	Winter on-peak	$0.058170	100.00%	$0.094919	100.00%
20	Winter off-peak	$0.043170	74.21%	$0.022905	24.13%
	Interruptible Power Service TOU				
21	Summer on-peak	$0.071861	100.00%	$0.097611	100.00%
22	Summer Shoulder	$0.059691	83.06%	$0.048927	50.12%
23	Summer off-peak	$0.056861	79.13%	$0.037611	38.53%
24	Winter on-peak	$0.059411	100.00%	$0.097611	100.00%
25	Winter off-peak	$0.044411	74.75%	$0.022479	23.03%

Hours:
Summer on-peak: 2:00 p.m. To 6:00 p.m.
Summer Shoulder Peak: 12:00 p.m. To 2:00 p.m. And 6:00 p.m. To 8:00 p.m.
Summer Off Peak: 12:00 a.m. To 12:00 p.m. And 8:00 p.m. To 12:00 a.m.
Winter On-Peak: 6:00 a.m. To 10:00 a.m. And 5:00 p.m. To 9:00 p.m.
Winter Off Peak: 12:00 a.m. To 6:00 a.m., 10:00 a.m. To 5:00 p.m., and 9:00 p.m. To 12:00 a.m.

REFERENCES:
UNSE Schedule H-3

UNS ELECTRIC, INC.
PROPOSED SUPER PEAK TOU RATES

DOCKET NO. E-04204A-09-0206
SCHEDULE BJ-13

LINE NO.		(A) Proposed Rate	(B) Percent of Super Peak
	Residential Super Peak		
1	Summer Super-peak	$0.482730	100.00%
2	Summer Shoulder	$0.068767	14.25%
3	Summer off-peak	$0.048113	9.97%
4	Winter on-peak	$0.153093	100.00%
5	Winter off-peak	$0.035849	23.42%
	Small General Service Super Peak		
6	Summer Super-peak	$0.417820	100.00%
7	Summer Shoulder	$0.066778	15.98%
8	Summer off-peak	$0.040888	9.79%
9	Winter on-peak	$0.130888	100.00%
10	Winter off-peak	$0.032668	24.96%
	Large General Service Super Peak		
11	Summer Super-peak	$0.358480	100.00%
12	Summer Shoulder	$0.059129	16.49%
13	Summer off-peak	$0.041024	11.44%
14	Winter on-peak	$0.116024	100.00%
15	Winter off-peak	$0.027306	23.53%

Hours:

Summer Super- Peak:
Version A: 2:00 p.m. to 3:00 p.m.;
Version B: 3:00 p.m. to 4:00 p.m.;
Version C: 4:00 p.m. to 5:00 p.m.; or
Version D: 5:00 p.m. to 6:00 p.m.

Summer Shoulder-Peak:
Version A: 3:00 p.m. to 6:00 p.m.;
Version B: 2:00 p.m. to 3:00 p.m. and 4:00 p.m. to 6:00 p.m.;
Version C: 2:00 p.m. to 4:00 p.m. and 5:00 p.m. to 6:00 p.m.; or
Version D: 2:00 p.m. to 5:00 p.m.

Summer Off -Peak:
12:00 a.m. (midnight) to 2 p.m. and 6:00 p.m. to 12:00 a.m. (midnight)

Winter On-Peak: 6:00 a.m. To 10:00 a.m. And 5:00 p.m. To 9:00 p.m.
Winter Off Peak: 12:00 a.m. To 6:00 a.m., 10:00 a.m. To 5:00 p.m., and 9:00 p.m. To 12:00 a.m.

<u>REFERENCES:</u>
Exhibit DBE-3A